STATE OF SOUTH CAROLINA
BEFORE THE PUBLIC SERVICE COMMISSION
DOCKET NO. 2019-9-E

In the Matter of: South Carolina Electric & Gas Company's Integrated Resource Plan	)))))	COMMENTS OF SOUTH CAROLINA COASTAL CONSERVATION LEAGUE AND SOUTHERN ALLIANCE FOR CLEAN ENERGY

The Coastal Conservation League and the Southern Alliance for Clean Energy ("CCL/SACE") request that the Commission closely scrutinize the 2019 Integrated Resource Plan ("IRP") filed by Dominion Energy South Carolina ("DESC's"), for a number of reasons.

First, the IRP is the basis of DESC's avoided cost rates, which if set too low deter cost-effective competition by independent power producers. DESC uses the difference in revenue requirement ("DRR") methodology to calculate avoided cost rates.[1] The DRR methodology, in turn, is driven by the Company's underlying resource portfolio as identified in its most recent IRP. Thus, any change in the IRP will impact avoided cost rates and will, further, change the basis of cost recovery under the Company's distributed energy resource ("DER") rider.

Second, the IRP lays the groundwork for future rate increases or decreases. It is the Commission's most significant opportunity to ensure that the Company diligently evaluates potential system-wide cost saving options *in advance* to minimize future revenue requirements (i.e., future customer bills) and is reasonably avoiding risks such as unnecessary or overly-costly infrastructure, fuel cost volatility, and being "caught off

[1] *See* Direct Testimony of Joseph M. Lynch, PSC Docket No. 2018-2-E, page 4 (filed Feb. 23, 2018) (explaining that the Company uses the DRR method). *See also* Direct Testimony of James Neely, PSC Docket No. 2019-2-E, page 6 (Feb. 8, 2019) (prefiled testimony in the Company's 2019 fuel cost proceeding that was bifurcated pursuant to Commission Order No. 2019-229).

base" by technological developments, regulatory change, or load forecasting error.

CCL/SACE make the following recommendations to improve DESC's IRP, both now and going forward. Our recommendations embrace common best practices for IRP development while also ensuring compliance with the Energy Freedom Act ("EFA"), House Bill 3659, signed into law by Governor Henry McMaster May 16, 2019. Under the EFA, the Commission must determine whether a utility's IRP is the "most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed."[2] The recommendations set forth below will assist in that undertaking.

I. The Commission Should Insist that DESC Use Optimization Modeling Software, Reveal Complete Cost Scenarios, and Include Retirements

DESC has for the first time in recent history included more than one potential future generation portfolio in its IRP—a significant step forward. While DESC's nineteen resource plans suggest potential cost savings, unfortunately the IRP has not been conducted in such a way as to yield a least-cost, actionable plan that thereby enables accurate calculation of avoided costs.

Sound planning requires the utilization of software that looks for the right portfolio of utility resources to optimize costs. A recent presentation by the Electric Power Research Institute (the "think tank" arm of the electric utility trade organization Edison Electric Institute) explains the functioning of one example of such modeling (EGEAS) as follows:

1. Automates the classical planning method, and evaluate[s] all possible combinations of resources plans to reach the optimal, least-cost plan.

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[2] SC Code Annotated Section 58-37-40(C)(2).

2. Users input load forecast, costs and characteristics of existing and potential resources, purchase power contracts, and all future potential planning options.

3. Users run the optimization model, sit back, relax, enjoy a cup of coffee... and get the "right" answers.[3]

The presentation lists seven other common optimization models[4] and many more are used by utilities around the country.

DESC, however, does not currently use optimization software for IRP planning.[5] This is a problem not only because ratepayers are paying for utility planning that does not adequately analyze options for cost reduction, but also because FERC *requires* optimization for utilities that calculate avoided costs using a difference in revenue requirement ("DRR") method, as DESC does.[6]

Because DESC does not perform optimization, its 19 portfolios are, at best, 19 "educated guesses" as to which direction the utility should take. While they provide more information than a single portfolio (DESC's practice for the past decade), they do not perform the essential function of seeking the least cost plan under a defined set of reasonable input assumptions.[7]

CCL/SACE's first recommendation, therefore, is that the Commission should direct DESC to adopt utility best practices in resource planning and employ appropriate optimization software to "automate the classical planning method, and evaluate all

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[3] *See* https://eea.epri.com/pdf/NG%20Planning_EPRI_EGEAS_Webcast_041615_Final.pdf (slide 11).
[4] *Id.* at Slide 18.

[5] SCE&G expert Joseph Lynch. VOLUME 9 - Live Testimony 11/13/2018. MERITS HEARING 2017-207-E, -305-E, -370-E Page 2468, in which Dr. Lynch indicated that "in the near future, we will have more–better models to study all the options."

[6] FERC Order No. 69, Federal Register at Vol. 45, No. 38, 12216.

[7] DESC's resource planning methodology compares the cost of pre-designed, staff-selected portfolio on a head-to-head basis. Optimization resource planning, on the other hand, identifies the least-cost scenario that meets system needs from among the thousands of potential combinations of resource additions and retirements.

possible combinations of resource plans to reach the optimal, least-cost plan," by inputting the relevant data and assumptions and allowing the model to optimize for the "right" answers.

With that understanding, CCL/SACE turn briefly to the two resource portfolios highlighted by DESC. The first is DESC's preferred plan (Resource Plan 7"), which is based on adding a natural gas combined-cycle ("NGCC") power plant in 2029 and another one in 2040.[8] The second plan is the "runner up" in cost scoring ("Resource Plan 17"), which is based on adding 400 MW of solar generation in 2026 plus ten additions of natural gas combustion turbine ("CT") generation over the eighteen year period between 2029 and 2047.[9]

It is CCL/SACE's understanding that DESC evaluates each resource plan under four scenarios: (1) base future gas prices with carbon pricing; (2) base future gas prices without carbon pricing; (3) high future gas prices with carbon pricing; (4) high future gas prices without carbon pricing (see Table 1, below). DESC then selects Resource Plan 7 as the basis of its avoided costs because it is the least-cost plan under one of these four scenarios (the "base case"). DESC explains that it selects the base gas price forecast scenario with no CO_2 cost to form the basis of avoided cost calculation because "the company assumes that base gas prices are the most likely gas scenario and CO_2 costs are uncertain at this point."[10]

[8] CCL will refer to a specific group of resources (such as SCE&G's existing fleet plus a new NGCC), as a "resource plan." CCL refers to assumptions about a specific set of future conditions as a "scenario." SCE&G evaluates 19 different resource plans under 4 different scenarios (base gas prices, high gas prices, and each of these gas price scenarios considered with and without carbon pricing).

[9] It is important to note here that, because each resource plan will have a different avoided cost, by selecting a particular plan (and by determining, in the first place, which plans would be compared) SCE&G essentially unilaterally sets its avoided cost.

[10] Direct Testimony of James Neely, Docket No 2019-2-E, Page 5.

CCL/SACE note that Resource Plan 17, under which DESC would add 400 MW of new solar in 2026, was the least-cost plan under three of the four scenarios developed by DESC.[11] Perhaps the more interesting point is that Resource Plan 17 ranked 4th out of 19 plans in the base case scenario. In other words, *Resource Plan 17 with 400 MW of new solar is among the lowest-cost plans under DESC's base case scenario* ***<u>and</u>*** *is the least cost plan under every other scenario*.

Table 1: SCE&G Scenario Ranking from 2018 IRP

		Scenario Ranking			
Scenario Number	Scenario	$0 CO2, Base gas	$15 CO2, High gas	$0 CO2, High gas	$15 C02, Base Gas
7	CC 540 MW x 2	1	10	10	6
17	Solar PPA 400 MW w/ICT 93 MW ($30)	4	1	1	1

The same cannot be said for DESC's chosen Resource Plan 7. If gas prices turn out to be higher than currently projected, Resource Plan 7 falls to the bottom half of the cost ranking (10th, with or without a carbon price). If a carbon price materializes, even without increased natural gas costs, Resource Plan 7 ranks 6th. Resource Plan 17 appears to be more robust than Resource Plan 7 against the cost risks that DESC identifies, without losing much in the ranking under the projected base case scenario.

The comparison of Resource Plans 7 and 17 reveals four other major issues. The first is that DESC does not provide the cost of each scenario. Because the rankings lack relative cost information, it is impossible to identify which resource and price assumptions result in meaningful differentiation and which are insignificant . [12] A reader

[11] SCE&G 2019 IRP at 45, line 17.

[12] In its Virginia IRP, Dominion provides its estimate of the total cost of implementing each portfolio. *See*, for instance, the projected total costs for five different future plans, ranging from roughly $25 billion to $31 billion at page 18 of its recent Virginia compliance filing:

cannot tell whether the fourth-ranked Resource Plan is significantly more expensive than the first, or only slightly more expensive. If the difference is small, then Resource Plan 17 is preferable overall because Portfolio 17 is first in all other scenarios. Further, the missing cost data should be provided in a manner that allows stakeholders to understand how costs for each plan are incurred over time, on an annual basis, and what financial assumptions the Company is using. If two plans are very close in overall cost, but one requires major near-term investment and the other does not, it may be less risky to pursue a plan that does not "tie the hands" of the ratepayer through large upfront costs. These are exactly the kinds of cost considerations that might have helped avoid the VC Summer debacle and that led to the development of integrated resource planning in the first place.

A second major issue is the choice to use a long-term economic analysis window that likely inappropriately obscures the ranking of decisions within the 15-year planning horizon. The purpose of the IRP is to consider what actions taken during the next 15 years (through the year 2034) will result in a least-cost plan. Therefore, the economic analysis and ranking of scenarios should be based on this same 15-year time horizon. DESC, however, uses a 40-year time window for its ranking of different plans without explanation. Rather than evaluating only the 40-year window, DESC should also calculate and consider the net present value cost and rankings for each scenario over the more relevant 15-year planning horizon. This will allow DECS to isolate the impact of the less-certain far-off resource decisions from the more important short-term planning decisions.

It is problematic to make near-term (15-year) planning decisions based on

http://www.scc.virginia.gov/docketsearch/DOCS/4f0801!.PDF. We suggest that similar cost estimates, additionally broken down in an annual series, should be the norm for filings in South Carolina.

analysis intended to assess a much longer-term and window marked by significantly more uncertainty. The majority of the 40-year window for economic analysis (25 years) occurs after the 15-year planning horizon, and significant investments are made in that 25 year period. In the case of Resource Plan 7, for example, a $500 million natural gas combined cycle plant (half of the plan's new investment) would be added in 2040, long after the 15-year decision-making window. Similarly, in the case of Resource Plan 17, seven of ten additional gas peaking plants—nominally costing a total of around $450 million—would be added in seven different years after the 15-year window.

This matters because the economic analysis of the key near-term decisions that will set the utility on a course towards Resource Plan 7 or Resource Plan 17—whether to increase solar or whether to increase natural gas generation in the 2020's—are being driven by non-comparable additions that would occur outside the 15 year window for analysis and decision. Estimates about the cost or need for a 540 MW gas plant in 2040 twenty years from now should not drive its decision about whether to increase solar or gas generation in within the next decade. The further these additions are into the future, and the larger they are, the more uncertain it is that the IRP cost analysis actually provides a reasonable comparison of the possible paths forward in the near to mid-term. While choosing the correct timeframe for analysis is not an exact science, DESC's analysis should ensure a relevant, apples-to-apples comparison of the cost of decisions being made within the 15-year planning horizon.

Further, this issue links back to the need, discussed above, for DESC to reveal the actual overall and annual cost (in terms of net present value) of each scenario. Combined with a reasonable window of economic analysis and comparability for any out-year costs, a transparent cost comparison between scenarios will help guide the utility, commission, and stakeholders towards the least-cost, least-risky plan.

A third major issue is DESC's failure to fully explore plant retirement opportunities, using optimization modeling, ***on an economic basis***. Both Resource Plan 7 and Resource Plan 17, for example, assume that existing 60-year-old, inefficient gas steam units will stay on the books and operate for 40 more years—for a total of 100 years. These two scenarios also assume that coal plants that have already operated for 40-50 years will last another 40 years. These assumptions appear unrealistic and render both plans (and the associated cost ranking and avoided cost calculations) suspect in their current form.

In the past, IRPs focused on the selection of new generation investments to meet steady load growth, with old assets frequently being assumed to retire at the end of their useful lives. But with flat load growth and promising new technologies presenting opportunities to retire old assets at a net cost savings to ratepayers, utilities and the Commission must proactively assess all economic retirement opportunities to ensure that ratepayers are not needlessly subsidizing non-economic assets that will stay "on the books," earning a rate of return despite the availability of cheaper and cleaner alternatives.

This issue of examining plant retirement opportunities links back to the issue of optimizing resource portfolios: implicit in the search for the optimal portfolio is the concept that generation units within the existing utility fleet are not "baked into" the modeling, but rather is allowed to retire if assets that are more economic over the analysis period are available. The exact year of asset retirement can be refined as part of a retirement plan, but if the optimization model is prevented from discovering economically-indicated plant retirements (as appears here), then opportunities for ratepayer savings will be actively obscured.

Fourth, the comparison of Resource Plans 7 and 17 reveals an underlying failure to consider and model reasonable expansion of demand-side management programs. Despite clear direction from the Commission in last year's annual fuel cost proceeding to consider additional Demand Side Management and Energy Efficiency measures targeted at reducing load during winter peaks, DESC's currently-filed plan assumes that it will actually implement 100 MW *less* winter DR than in the prior year.[13] The assumption that winter DR will decline and that DSM in general will not significantly expand likely changes the cost comparison among resource plans because the purpose of DSM programs is to delay the need and reduce the size of infrastructure and to provide lower-cost solutions, particularly in hours such as winter peak. DESC should conduct robust DSM potential and cost-effectiveness analysis and develop a reasonable and defensible DR and EE plan to integrate into the optimization recommended above.

In addition to these four methodological shortcomings, CCL/SACE would be remiss not to identify two environmental issues that should be addressed prospectively in order to facilitate the Commission's review under the new EFA.

The EFA requires the Commission to balance a list of factors in determining whether an IRP represents the most reasonable and prudent plan, including "commodity price risk."[14] Natural gas, coal, and nuclear fuel are commodities with greater or lesser

[13] Direct Testimony of Devi Glick, PSC Docket No. 2019-2-E, page 13 (Mar. 19, 2019) (prefiled testimony in the Company's 2019 fuel cost proceeding that was bifurcated pursuant to Commission Order No. 2019-229). .

[14] SC Code Annotated Section 58 37 40 (C)(2)(e).

price fluctuations (with natural gas price fluctuation being the classic example of commodity price risk). As part of the cost comparison between portfolios, the IRP should quantify the greater and lesser commodity price risks that accompany portfolios.

In addition, some resource portfolios and scenarios will have foreseeable environmental regulatory compliance costs that other portfolios do not. For instance, DESC reports in the current IRP that it is conducting studies at the Urquhart and Williams power plants to determine whether modifications are needed to the cooling water intake structures at these two plants to comply with Clean Water Act Section 316(b).[15] DESC also reports that "wastewater treatment technology retrofits will be required at Williams and Wateree" in order to comply with federal Effluent Limitation Guidelines.[16] A reasonable estimate of the cost of these foreseeable upgrades should be provided in the IRP, incorporated within its modeling, and reflected as an avoidable cost if the model selects an alternative resource portfolio leading to the retirement of these units.

DESC's provision of an analysis that reasonably quantifies the commodity price risk, foreseeable environmental regulatory compliance costs, and identifies the least cost plan or plans considering these costs will assist the Commission in fulfilling its duty to balance these factors in reviewing the Company's IRP.

It may be obvious from the range of issues raised above that good faith engagement of stakeholders could help narrow the scope of potential disagreements in the IRP process and increase its effectiveness for ratepayers. CCL/SACE respectfully propose that the Commission direct DESC to convene stakeholders well in advance of its

[15] SCE&G 2019 IRP at 32-33.

[16] *Id.* at 34.

development of a final IRP for filing in 2020, in order to share modeling input assumptions and parameters so that stakeholders can attempt to agree on which modeling runs and approaches are essential for the 2020 IRP. This process should be facilitated by a neutral third party.

In light of the issues and comments discussed above, CCL/SACE urge the Commission to direct DESC to take the following actions:

- Fully employ the capability of software that optimizes its resource portfolio over the next 15 years, taking into account any economic resource retirement opportunities and fully reflecting cost-effective demand-side resources as identified in robust potential and cost-effectiveness analysis.
- Require that DESC makes all model inputs, assumptions transparent, and provides all model outputs to allow for intervenor review (under appropriate confidentiality procedures) of all results and modeling decisions.
- Provide a transparent and more detailed cost comparison of the resource plans (including alternatives considered in retirement analyses) on an overall basis and on an annual basis, including all material assumptions affecting the cost comparison, and with a reasonable focus on the costs of decisions made within the 15-year planning window. The cost analysis should quantify commodity price risks and should clearly identify foreseeable environmental regulatory cost risks, taking them into account in retirement analysis.
- Model significant expansions of demand-side management and efficiency programs to lower overall system load and winter peaks.
- Engage stakeholders in a timely manner before development of the 2020 plan

to explain modeling inputs and assumptions and enable development and evaluation of any alternative plans or scenarios prior to the filing of the 2020 plan.

II. Natural Gas Generation and Pipelines

The IRP includes an additional significant deficiency with regards to system planning and natural gas transmission capacity. The only type of baseload generation added to DESC's fleet within its nineteen scenarios is combined cycle gas-fired generation.[17] There is no new coal and no new nuclear (for obvious reasons).[18] In fact, new natural gas generation appears in fourteen of the nineteen scenarios.[19] And yet, there is no discussion of the multi-million dollar cost of delivering fuel to those potential new units. Any IRP that adds new gas-fired generation to the Company's fleet must include as part of that analysis a detailed discussion of the fuel delivery logistics and costs associated with those new gas-fired units. Moreover, not all peak hours are the same. To the extent a utility intends to add new peaking resources, the IRP should include a discussion of when those peak hours occur and an evaluation of which types of resources best fit the load profile at a given time of day. The complete absence of fuel delivery planning shows that this IRP is anything but integrated.

a. SCE&G is not using the IRP to guide its pipeline capacity contracting

Interstate natural gas pipeline contracts are multi-decade, multi-million dollar commitments, which ratepayers historically underwrite. DESC should use the IRP

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[17] IRP at 41.

[18] *See* IRP at 41.

[19] IRP at 41.

process to guide its pipeline contracting decisions, but the evidence here suggests that is not happening. In fact, DESC has already executed two new firm[20] pipeline transportation contracts that it does not need but for which it will attempt to charge ratepayers.

During the 2019 Review of Base Rates for Fuel Costs, Docket No. 2019-2-E, CCL/SACE presented the direct and surrebuttal testimony of Gregory M. Lander. Mr. Lander specifically addressed the unnecessary ratepayer costs that DESC will likely seek to impose on its customers related to two upcoming long-term contracts DESC has executed with the Mountain Valley Pipeline and the Southeastern Trail pipeline project.[21] Information contained in this IRP and supporting discovery confirms Mr. Lander's opinion: DESC does not need either of these new pipeline contracts, or any new pipeline capacity in the near future.

Of the nineteen scenarios modeled in this IRP, fourteen include new natural gas-fired generation. None of these fourteen scenarios, however, contain new baseload gas-fired generation before 2029 – ten years from now.[22] On current construction schedules, Southeastern Trail and Mountain Valley Pipeline will go into service in 2020 or 2021, at which point DESC will begin paying the fixed annual contract prices and passing those costs on to customers. In short, the IRP confirms that SCE&G has no need for new pipeline capacity to deliver fuel to ***new*** plants until at least 2029.

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[20] "Firm" means that the Company will pay a fixed annual rate for exclusive use a certain amount of pipeline space. The Company will pay this contract price regardless of how much of the pipeline capacity it actually uses in any given year. Alternatively, the Company can purchase pipeline capacity on an "interruptible" basis, where it only pays for what it needs when it needs it. Interruptible capacity, however, is not guaranteed to be available when it is needed most, which is why it is prudent for the utility to have a certain amount of firm transportation capacity in its portfolio.

[21] Docket No. 2019-2-E, Lander Direct at 18, 20.

[22] *Id.* at 42-44.

Likewise, the IRP demonstrates that DESC does not need new firm pipeline capacity to deliver fuel to its ***existing*** gas plants either. The Company has never even studied whether there are gas delivery constraints to serve its existing fleet.[23] The Company has also failed to study alternative options for delivering fuel to the existing fleet.[24] Even scenarios that consider reductions in coal generation within the Company's existing generation fleet do not support acquisition of new pipeline capacity. Scenario 6 retires a coal plant, but the Company has conducted no study regarding natural gas delivery constraints within its system in the event the Company retires any coal-fired unit before the coal-fired unit is fully depreciated.[25] In short, none of the nineteen scenarios support the Company's decision to add new firm pipeline capacity to its fuel delivery portfolio, because there simply is no need for such capacity either for existing or new plants.

There is also nothing in this IRP demonstrating a claim that new pipeline contracts provide diversity or increased reliability. In the Fuel Docket, DESC witness Darrin Kahl stated that "[c]ontracting for firm capacity provides substantial supply reliability benefits compared to purchasing large volumes of supply and firm transportation capacity on the daily spot market."[26] This is true up to a point, which Mr. Lander addressed in his direct testimony: "There can be value to the utility, and to the ratepayer, in being able to shift purchases from one supply location to another. To do

[23] SCE&G Response to CCL/SACE Interrogatory 2 (attached as Exhibit 1).

[24] SCE&G Response to CCL/SACE Request for Production 7 (attached as Exhibit 2).

[25] SCE&G Response to CCL/SACE Interrogatory 4 (attached as Exhibit 3).

[26] Kahl Rebuttal at 9:11-13.

that, utilities need multiple transportation contracts."[27] Mr. Lander goes on to state, however, that "a utility should add new pipeline transportation contracts only to the extent those new contracts are needed to meet reasonable projections of demand and provide *ratepayer* value."[28] Having access to diverse pipeline can also, in theory, provide price relief when natural gas commodity prices in one supply area spike. A utility cannot, however, look at those commodity price spikes in a vacuum; the utility must also consider the cost implications of *accessing* those other, possibly cheaper, supply areas. A utility should only add new capacity if the "all in cost" (*i.e.*, the commodity plus transportation cost) justifies it. If the contract does not provide ratepayer value, ratepayers should not pay for it. The IRP, which is supposed to integrate the disparate pieces of utility operations, should assist the Company in identifying where, when, and what new pipeline capacity a utility needs given its load serving obligations over time.

The Mountain Valley and Southeastern Trail contracts are examples of a bigger problem – the lack of truly *integrated* planning. Right now, DESC is making real-world, multi-decade, multi-million dollar decisions that have no basis in – and are not supported by – the IRP. The IRP is an opportunity for this Commission to gain insight into what the utility is planning to do in the future, which is critical considering how many ratepayer dollars are involved. When the Commission lacks adequate information, ratepayers suffer.

b. The IRP Should consider Natural Gas Costs – Both Commodity and Transportation

An IRP should involve least-cost planning to reliably deliver electricity. As part

[27] Lander Direct at 16:10-12.

[28] Lander Direct at 16:18-20 (emphasis in original).

of that process, the Commission should require DESC in future IRPs to

- Assess generation and associated fuel logistics load factors for any existing or new supply-side resources;
- Study and present an analysis of the cause, frequency, duration or magnitude of natural gas price spikes and assess what infrastructure developments are already underway and under development that could reduce, if not eliminate, the frequency, duration, and magnitude of such price spikes;
- Study the availability of vaporized LNG as a reasonable source of supply which could be delivered through existing lines on peak demand hours and days; thereby avoiding the fixed costs of additional pipeline capacity;
- Analyze the Company's load serving requirements and projected load serving requirements with demand duration curves as part of their least-cost planning to determine whether the load factor of its projected demands is so low that meeting such demands only with gas-fired units is not prudent due to the necessity to incur fixed-costs.

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In closing, while CCL/SACE commend DESC for incrementally improved practices in its 2019 IRP that allow some evaluation of resource portfolios for potential opportunities for ratepayer savings, DESC should implement the best practices described in these comments to fully explore how different scenarios could save ratepayers money and reduce risk. CCL/SACE request that the Commission require DESC to implement the IRP recommendations described above.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
SOUTH CAROLINA COASTAL CONSERVATION LEAGUE AND
SOUTHERN ALLIANCE FOR CLEAN ENERGY'S
FIRST SET OF INTERROGATORIES AND
REQUESTS PRODUCTION OF DOCUMENTS
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INTERROGATORY 2:

Has the Company conducted any study, analysis, report (or retained any third party to conduct any study, analysis, or report) regarding natural gas delivery constraints to serve its existing fleet?

RESPONSE 2:

No.

**SOUTH CAROLINA ELECTRIC & GAS COMPANY
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REQUEST 7:

For each of the Company's existing natural gas-fired units, for each scenario, please provide the alternative fuel delivery options, if any.

RESPONSE 7:

There were no alternative fuel delivery options modeled in the scenarios.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
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INTERROGATORY 4:

Has the Company conducted any study, analysis, report (or retained any third party to conduct any study, analysis, or report) regarding natural gas delivery constraints within its system in the event the company retires any coal-fired unit before the coal-fired unit is fully depreciated?

RESPONSE 4:

No.